STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE JACOB S. GERTSMAN

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF (2017)	)	**BPU DOCKET No. ER17030308** **OAL DOCKET No. PUC 04989-17**

JOINT TESTIMONY OF
CHARLES SALAMONE AND MAXIMILIAN CHANG
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

STEFANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

DIVISION OF RATE COUNSEL
140 East Front Street, 4th Floor
P. O. Box 003
Trenton, New Jersey 08625
Phone: 609-984-1460
Email: njratepayer@rpa.state.nj.us

FILED: August 1, 2017

PUBLIC VERSION

TABLE OF CONTENTS

Page No.

I. STATEMENT OF QUALIFICATIONS

Q. Would the members of the Engineering Panel Review ("Panel") please state your names, positions, and business address.

A. My name is Charles Salamone, PE. I am Owner of Cape Power Systems Consulting, LLC a power systems consulting Company with an address of 630 Cumberland Dr., Flagler Beach, Florida and I am subcontracting with Synapse Energy Economics, Inc. ("Synapse").

My name is Maximilian Chang. I am a Principal Associate with Synapse Energy Economics, an energy consulting company located at 485 Massachusetts Avenue, Cambridge, Massachusetts.

Q. On whose behalf are you submitting testimony in this proceeding?

A. We are submitting testimony on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel").

Q. Mr. Salamone, please describe your education and professional background.

1. I hold a Bachelor of Science Degree in Electrical Engineering from Gannon University. I joined the Engineering Department of Commonwealth Electric Company in 1973. At that time, I became a Junior Planning Engineer where my primary responsibilities were to assist in the planning, analysis, and design of the transmission and distribution systems of Commonwealth Electric Company, later known as NSTAR. I generally followed the normal progression of positions with increasing levels of responsibility within the planning area until taking the position of Director of System Planning at NSTAR in 2000. I held that position

until starting Cape Power Systems Consulting, LLC in 2005. During my career with NSTAR, in addition to the responsibilities associated with overseeing System Planning, I served as Chair of the New England Power Pool (NEPOOL) Planning Policy Subcommittee (1997-1998), Chair of the NEPOOL Regional Transmission Planning Committee (1998-1999), and Vice Chair of the NEPOOL Reliability Committee (1999-2000). As a consultant, I have been providing consulting services to a number of power system industry clients since 2005. I am a Registered Professional Engineer with the Commonwealth of Massachusetts. I am also a senior member of the Power Engineering Society of the Institute of Electrical and Electronic Engineers. A copy of my resume is attached hereto as **Attachment RC-ENG-1**.

Q. Mr. Salamone, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the New Jersey Board of Public Utilities ("BPU" or "Board"), the Federal Energy Regulatory Commission ("FERC"), the Massachusetts Department of Public Utilities, and the Massachusetts Energy Facilities Siting Board on a number of technical matters relating to ratemaking and system planning.

Q. Mr. Chang, please describe your professional background at Synapse Energy Economics.

A. My experience is summarized in my resume, which is attached as **Attachment RC-ENG-2**. I am an environmental engineer and energy economics analyst who has analyzed energy industry issues for eight years. In my current position at

Synapse Energy Economics, I focus on economic and technical analysis of many aspects of the electric power industry, including: (1) utility mergers and acquisitions, (2) utility reliability performance and distribution investments, (3) nuclear power, (4) wholesale and retail electricity markets, and (5) energy efficiency and demand response alternatives. I have been an author and project coordinator for the last two biennial New England Avoided Energy Supply Component reports, which were used by energy efficiency program administrators in the six New England states to evaluate energy efficiency programs.

Q. Mr. Chang, please describe your educational background.

A. I hold a Master of Science degree from the Harvard School of Public Health in Environmental Health and Engineering Studies, and a Bachelor of Science degree from Cornell University in Biology and Classical Civilizations.

Q. Mr. Chang, have you previously submitted testimony before the Board of Public Utilities?

A. Yes. I filed testimony before the Board in dockets GO12050363 (South Jersey Gas Energy Efficiency), EM140460581 (Exelon-PHI Merger), ER14030250 (RECO Storm Resiliency), and GM15101196 (AGL Southern Company Merger).

Q. Mr. Chang, have you previously testified before utility regulatory agencies?

A. Yes. I have previously testified before the District of Columbia Public Service Commission, the Hawaii Public Utilities Commission, the Illinois Property Tax Appeal Board, the Maine Public Utilities Commission, the Maryland Public Service Commission, and the Massachusetts Department of Public Utilities. I have also filed testimony before the Delaware Public Utilities Commission, the

Kansas Commerce Corporation, the Illinois Commerce Commission, and the United States District Court for the District of Maine.

II. PURPOSE AND SUMMARY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to review engineering and reliability aspects of Atlantic City Electric's (the "Company" or "ACE") petition to raise electric distribution rates and to seek approval from the New Jersey Board of Public Utilities (the "Board") for the implementation of a System Renewal Recovery mechanism.

Q. Please summarize your findings and recommendations.

A. Our findings and recommendations are summarized as follows:

- ACE has met the goals of the 2011 Reliability Improvement Plan ("RIP") thus alleviating the need for the Company to continue spending on the RIP. RIP capital spending represented an increase in the Company's overall distribution capital spending to permit restoration of the Company's reliability performance to acceptable levels. This higher expenditure rate was needed to bring the Company's poor reliability performance up to acceptable levels and should now return to a more normalized level. We recommend that the Company discontinue capital and expense budget spending under the RIP program. Instead the Company should identify projects and programs to improve reliability based on a prioritization process that is based on assessment of costs and reliability benefits, at least cost to ratepayers, rather than one that is based on fixed budget allocations. We similarly recommend that the Company should cease operational spending through its Enhanced Integrated Vegetation Management program, which is a subset of the RIP. Instead, we recommend that the Company quantify the expected spending associated with the new vegetation management regulations and base its spending on those requirements.

- The Board should reject the Company's proposed System Renewal Recovery ("SRR") mechanism since the proposed program predominantly includes blanket spending that should be part of the Company's normal course of business and does not warrant special rate treatment.
- The Board should reject the Company's post-test year adjustments since most of the adjustments are generally for programs and blankets. The Company has not demonstrated that any of the post-test year adjustments are major in consequence as set forth in standard of review found in the Elizabethtown Water Company case.[1] Individual projects of more than $100,000 in capital spending only represent $3.2 million of the $52 million post-test year adjustments proposed by the Company.

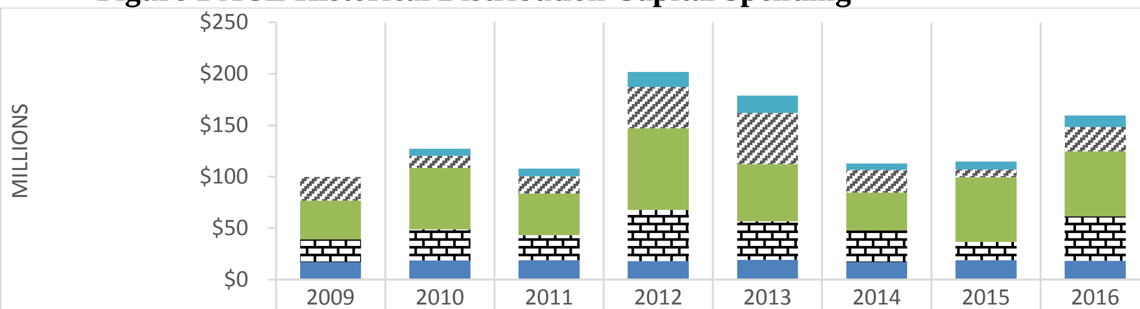
[1] See In Re Elizabethtown Water Company Rate Case, BPU Docket No. WR8504330, Decision (5/23/85).

III. HISTORICAL DISTRIBUTION CAPITAL SPENDING

Q. Please summarize the Company's historical spending on its distribution system.

A. Mr. Michael Sullivan's testimony that has been adopted by Mr. William Ruggeri provides a summary of the Company's historical capital spending through 2016.[2] We have provided a graphical representation of the Company's overall distribution capital spending.

Figure 1 ACE Historical Distribution Capital Spending[3]



	2009	2010	2011	2012	2013	2014	2015	2016
General Plant		$6.9	$7.4	$14.6	$16.9	$6.1	$7.5	$11.2
Load Growth	$23.0	$12.0	$16.7	$40.1	$49.6	$22.3	$7.5	$23.6
Reliability Emergency	$37.7	$59.5	$40.6	$79.2	$55.6	$36.7	$62.8	$62.9
Reliability Planned	$22.0	$30.3	$24.1	$49.6	$37.5	$30.8	$17.9	$43.3
Customer Driven	$17.2	$18.6	$19.1	$18.2	$19.2	$17.0	$18.9	$18.4
Total	$99.9	$127.3	$107.9	$201.7	$178.8	$112.9	$114.6	$159.4

Figure 1 shows the breakdown of the five capital spending categories as defined by the Company. Overall, the Company's distribution capital spending has generally increased from 2009 and 2011 levels of approximately $100 million. In the last eight years, the Company has spent over $150 million per year in three instances, with the highest amount at $201.7 million in 2012. These expenditures

[2] Mr. William Ruggeri has adopted Mr. Michael Sullivan's direct testimony.
[3] Data from Direct Testimony of Michael Sullivan adopted by William Ruggeri; Direct Testimony of Michael Sullivan dated March 22, 2016 (BPU Docket No. ER16030252), Table 2; and Direct Testimony of Michael Sullivan dated March 14, 2014 (BPU Docket No. ER14030245), Table 3.

are inclusive of the Reliability Improvement Program and the higher amounts shown for 2012 through 2016 were driven primarily by implementation of the RIP program.

Q. What are the five budget categories of the Company's distribution capital spending?

A. The Company's definitions for the five categories of capital spending are listed below.[4]

Customer Driven: Projects required by customers, including connecting them to the distribution system and work performed at the direction of government agencies, such as electric plant relocations that support highway construction projects.

Reliability Planned: Projects to increase and maintain the reliability of the distribution system and electric facilities that provide service to the Company's customers. These projects include replacement of existing infrastructure, upgrades to reduce outages and improve system performance.

Reliability Emergency: Cost of emergency replacement of failed equipment during storms and other events.

Load Growth: Load projects are proactive additions or upgrades to the system in order to meet all levels of load in advance of those load conditions developing on the system. Load projects assure that the system continues to meet design criteria. This category of work does not include projects that are solely for the connection of new customers to the electric system.

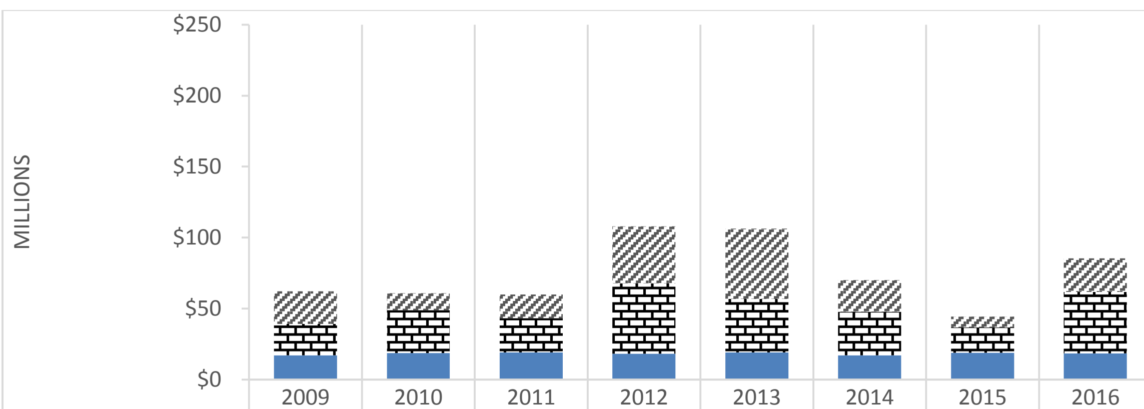
General Plant Investments in upgrades supporting infrastructure to maintain service centers and buildings across the Company's territory, new and upgraded Information Technology (IT) systems, transportation, mobile equipment, and support for the various communication systems needed for the operation of the electric system are all critical to ensuring the benefits of the Distribution Construction Program are realized.

[4] Direct Testimony of Michael Sullivan adopted by William Ruggeri, Table 1, page 4.

Q. Are there categories in the overall Distribution Capital Budget that may skew the observed spikes seen in the historical spending?

A. Yes, two items come to our attention: General Plant and Reliability Emergency spending. For 2009, the data that we have did not include spending for General Plant.[5] The historical spending level is also skewed by Reliability Emergency spending that fluctuates year to year because of major events that impact the ACE system. By excluding reliability spending for Reliability Emergencies and General Plant, we can see the Company's sustained investment on its distribution system as presented below.[6]

Figure 2 ACE Distribution Capital Spending Excluding Emergency Spending and General Plant[7]



	2009	2010	2011	2012	2013	2014	2015	2016
Load Growth	$23.0	$12.0	$16.7	$40.1	$49.6	$22.3	$7.5	$23.6
Reliability Planned	$22.0	$30.3	$24.1	$49.6	$37.5	$30.8	$17.9	$43.3
Customer Driven	$17.2	$18.6	$19.1	$18.2	$19.2	$17.0	$18.9	$18.4
Total	$62.2	$60.9	$59.9	$107.9	$106.3	$70.1	$44.3	$85.3

[5] RCR-ENG-122 asked for historical distribution capital spending for the period 2000-2016. The Company did not provide any data before 2010 in its response.
[6] As noted previously, the Company's 2009 values do not include General Plant categories.
[7] Data from Direct Testimony of Michael Sullivan adopted by William Ruggeri; Direct Testimony of Michael Sullivan dated March 22, 2016 (BPU Docket No. ER16030252), Table 2; and Direct Testimony of Michael Sullivan dated March 14, 2014 (BPU Docket No. ER14030245), Table 3.

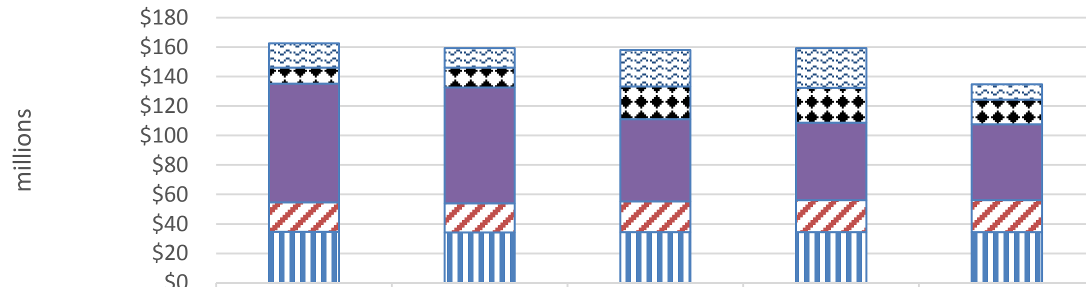
Figure 2 shows that the Company's distribution capital spending excluding Emergency spending increased dramatically in 2012 and 2013 due to the RIP program that we discuss in detail later in our testimony. On average, the Company's distribution capital (excluding Reliability Emergency and General Plant) spending for the period 2009-2011 was $65.8 million versus an average spending of $93.4 million for the period of 2012-2016.

IV. PROJECTED DISTRIBUTION CAPITAL SPENDING

Q. Please summarize the Company's proposed capital spending on its distribution system for the period 2017-2021.

A. Mr. Ruggeri's adopted testimony Table 4 provides a summary of the Company's proposed capital spending through 2021. We have provided a graphical representation of the capital spending below:

Figure 3 ACE Distribution Capital Budgets 2017-2021[8]



	2017	2018	2019	2020	2021
General Plant	$16.4	$13.2	$24.6	$26.9	$10.4
Load Growth	$10.9	$13.5	$22.2	$23.6	$16.8
Rel. Planned	$80.6	$78.5	$55.8	$52.6	$51.4
Customer Driven	$20.0	$19.9	$20.8	$21.8	$21.8
Emergency	$34.6	$34.2	$34.5	$34.4	$34.4
Total	$162.5	$159.3	$157.9	$159.3	$134.8

Figure 3 shows that the overall capital spending budgets between 2017 through 2020 are artificially levelized. The Company has accomplished this by increasing or decreasing elements of the distribution budgets. The Company has presented little evidence supporting these increases or decreases. For example, the Company's Load Growth projects increase from $10.9 million in 2017 to $23.6 million as shown above in Figure 3 even though historical distribution load growth forecasts, as shown in Figure 4 below, indicate almost flat distribution load growth. Moreover, the Company's expectation of future system demands has decreased for each year that a forecast of distribution system demands has been developed since 2013. On the other hand, the Company's Planned Reliability expenditures decrease from $80.6 million in 2017 to $52.6 million in 2020, and its General Plant budget increases from $13.2 million in 2018 to $24.6 million in 2019 as also shown in Figure 3.

[8] Direct Testimony of Michael Sullivan adopted by William Ruggeri, Table 4.

Q. Does the apparent levelized spending in the proposed budget reflect the Company's actual system needs?

A. The proposed levelized capital spending program does not appear to be based on specific forecast data but rather is an attempt at establishing a fixed spending program that may result in expenditures that are simply a means to satisfy the budget rather than to meet a specific need. We believe that the Company should use a comprehensive planning and prioritization process which seeks to prioritize projects and balance the costs and benefits of distribution system expenditures across its geographic service districts.

Q. Please give an example of the evidence that leads you to conclude that the Company's distribution budget may be designed to meet pre-determined spending goals rather than being formulated in response to system needs.

A. The Company's Load Growth projects are generally for projects that support increases in capacity in load growth pockets and potential load growth.[9] **<Begin Confidential>** [redacted] **<End Confidential>** The following figure shows trend in the Company's distribution load growth projections.

---

[9] Direct Testimony of Michael Sullivan adopted by William Ruggeri, page 15, lines 4-5.
[10] RCR-ENG-9 Attachments 2-5 Confidential.

Figure 4 ACE distribution load growth projections[11] **<Begin Confidential>**

[redacted]

<End Confidential>

Figure 4 shows that the Company has consistently overstated distribution load growth projection compared to actual load, and that distribution load growth projections have been lowered consistently over the last four years. The Company currently projects that its overall summer peak load will increase by **<Begin Confidential>** [redacted] **<End Confidential>** percent over the next ten years in absolute terms with a compound annual growth rate of **<Begin Confidential>** [redacted] **<End Confidential>** percent over the same period. While we acknowledge that there are individual pockets of load growth in the Company's overall system, the overall trend of the Company's distribution load growth is anticipated to be essentially flat over the next ten years. This will also impact individual projects. **<Begin Confidential>** [redacted]

[11] RCR-ENG-9 Attachments 2-5 Confidential.

[redacted] **<End Confidential>** Overall there are a number of projects included in the Company's projected capital spending budget that may not be needed given the Company's most recent load growth projections.

V. RELIABILTY IMPROVEMENTS

Q. Please summarize your findings regarding the Company's overall reliability performance.

A. As discussed in more detail below, we find that ACE improved its system reliability as measured by a number of reliability metrics. The Company has decreased its System Average Interruption Duration Index ("SAIDI") by 40 percent and its System Average Interruption Frequency Index ("SAIFI") by 26 percent for the period from 2009 to 2016. The Company has also met its 2011 Reliability Improvement Plan commitments and is on track to meet its 2020 reliability commitments from the 2015 Exelon merger settlement.

[12] RCR-ENG-18 Attachment 1.
[13] RCR-ENG-81 Confidential.

Q. Please summarize your assessment of the Company's reliability performance since 2011 as presented by the Company.

A. We agree with the Company's assessment that reliability has improved since 2011 with the implementation of the Company's RIP in BPU Docket No. ER09080664. As Mr. Ruggeri notes in his adopted testimony, the Company has seen a 33 percent improvement in its SAIFI, a 35 percent improvement in its SAIDI, and a 4 percent improvement in Customer Average Duration Index ("CAIDI").[14]

Q. You referenced several reliability metrics, please explain what each metric represents.

A. SAIDI is the metric that represents the average duration of sustained interruptions for the system during the year (in minutes). SAIFI represents the average frequency of sustained interruptions per customer during the year. CAIDI represents the average duration of sustained interruptions experienced by customers. Lower values for SAIDI, SAIFI, and CAIDI indicate improved reliability.

Q. Does the Company report a single value for each reliability metric?

A. No. The Company reports a value for reliability metrics that considers all events as well as a separate value that excludes "Major Events." "Major Events" are defined under N.J.A.C. 14:5 1-2 as interruptions affecting at least 10 percent of customers within an operating area.[15] This includes, but is not limited to

[14] Direct Testimony of Michael Sullivan adopted by William Ruggeri, page 2, lines 11-15.
[15] N.J.A.C. 14:5-1.2.

tornadoes, thunderstorms, snowstorms, heat waves, and ice storms.[16] Because Major Events are unpredictable, outages excluding Major Events is a better metric for determining general reliability of the Company's distribution system.

Q. Does your testimony address Major Events?

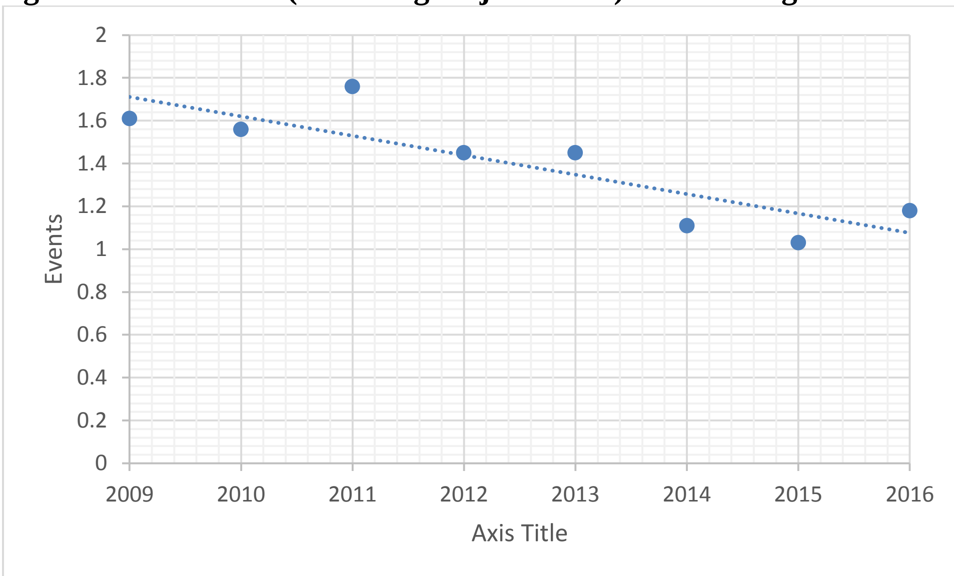
A. Not explicitly. Our testimony generally addresses the Company's reliability performance under "blue sky" conditions that exclude Major Events defined by New Jersey BPU regulations. It is our understanding that the settlement in Docket ER16030252[17] addressed the Company's distribution projects under Major Event situations. That said, projects such as vegetation management and distribution automation could have benefits for both blue sky and major event reliability.

Q. What has been the Company's reliability performance in the last few years?

A. The Company's reliability performance for both SAIDI and SAIFI have improved since 2009. The improvement in SAIFI is shown graphically below (Figure 5):

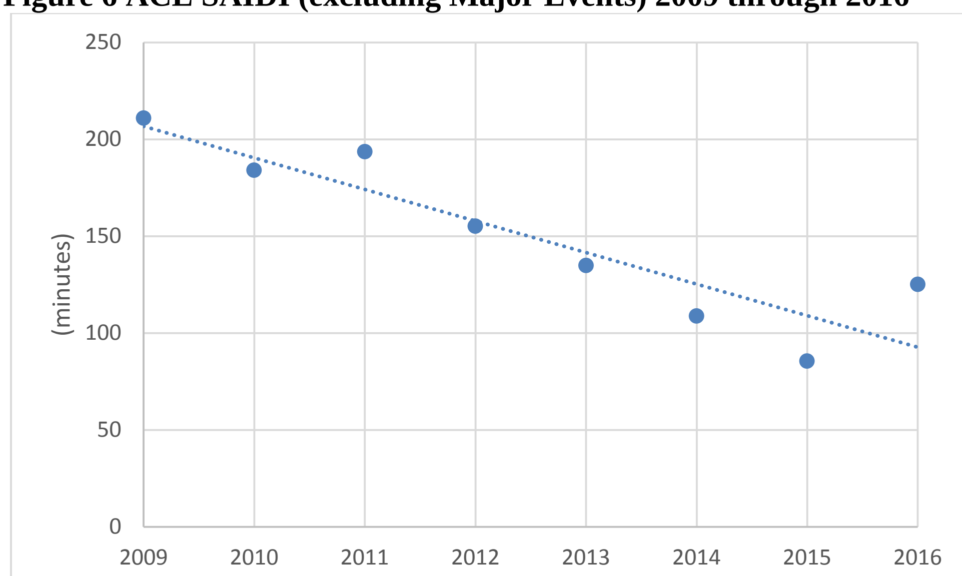
[16] Major Events also include periods when a Company provides mutual assistance to another utility.
[17] I/M/O ACE, BPU Docket No. ER16030252, Order Adopting Stipulation (5/31/17). ACE 2016 Base Rate Case.

Figure 5 ACE SAIFI (excluding major events) 2009 through 2016[18]



Since 2009, the Company's SAIFI has improved from 1.61 events to 1.18 in 2016, a 26 percent decrease. The following figure (Figure 6) shows Company's improvement in SAIDI since 2009 also shows similar improvement.

Figure 6 ACE SAIDI (excluding Major Events) 2009 through 2016[19]



[18] RCR-ENG-2 Attachments 3-8.
[19] RCR-ENG-2 Attachments 3-8.

The Company's SAIDI has improved from 211 minutes in 2009 to 125 minutes in 2016, a 40 percent decrease.

Q. Please explain why you are tracking the Company's reliability improvement from 2009 values instead of the 2011 values that are referenced in Mr. Ruggeri's adopted testimony.

A. While Mr. Ruggeri is correct that 2011 was the first year that the RIP program started, the baseline for comparison when the RIP was established were the 2009 reliability levels.[20] Therefore, we use the 2009 reliability metrics, instead of 2011, in our discussion of the RIP.

VI. RELIABILITY IMPROVEMENT PLAN

Q. Please summarize your findings about the RIP and the Company's performance relative to the RIP.

A. As stated above, the Company's reported SAIDI for 2016 was 40 percent below the 2009 baseline and its reported SAIFI for 2016 was 26 percent below the 2009 baseline. In short, the Company has met its RIP reliability goals, as discussed below. Therefore, we recommend that the Company discontinue the programmatic spending associated with the RIP, and focus on distribution spending required to maintain the observed trend in reliability improvement at the least cost to ratepayers.

[20] See I/M/O ACE, BPU Docket No. ER09080664, Order (May 16, 2011). Stipulation, page 19.

Q. Is the Company's RIP spending included in the Company's distribution capital spending and budgets shown earlier in your testimony?

A. Yes, the Company's RIP spending is included in the Company's distribution capital spending and budgets.

Q. What percentage of the Company's distribution capital spending has been categorized as RIP spending?

A. Based on the Company's response to RCR-ENG-12 and summarized in Figures 1 and 2, we present the representation of RIP spending as a percentage of total Distribution Capital and total Distribution Capital excluding General Plant and Reliability Emergency spending in the following table.

Table 1 RIP Spending as a Percentage of Distribution Capital Spending

		Key	2011	2012	2013	2014	2015	2016
All Distribution Capital	a	Figure 1	$107.9	$201.7	$178.8	$112.9	$114.6	$159.4
Distribution Capital (Ex. Emergency & General Plant)	b	Figure 2	$59.9	$107.9	$106.3	$70.1	$44.3	$85.3
RIP Spending	c	Figure 7	$36.5	$84.6	$87.9	$39.1	$23.9	$56.2
RIP As Percent of All Dist Cap	d=c/a		34%	42%	49%	35%	21%	35%
RIP As Percent of Dist Cap	e=c/b		61%	78%	83%	56%	54%	66%

Notes
Direct Tesimony of Michael Sullivan Table 2 Docket ER17030308
Direct Testimony of Michael Sullivan Table 2 Docket ER16030252
RCR-ENG-12 Attachment 1

The table shows that when General Plant and Emergency capital spending are excluded, the RIP capital spending has accounted for 56 to 83 percent of the Company's distribution capital spending. When including all categories, RIP capital spending has accounted for 21 to 49 percent of the Company's distribution capital spending. Investments in system reliability are an important part of any electric distribution company and they are necessary to maintain acceptable electric customer service. However, there is no longer a need to separately fund such improvements now that the Company has achieved the reliability goals that were set for it.

Q. Please explain your understanding of the genesis of the Company's RIP.

A. Concerns about ACE's reliability performance were one issue in the Company's 2009 base rate case (BPU Docket No. ER09080664). In that base rate case, the parties (Board Staff, Rate Counsel, and ACE) agreed to enter into a Phase II proceeding (BPU Docket Nos. EO09010049 and EO09010054) to address reliability concerns among other matters. Through discovery and discussions between 2010 and 2011, the three parties agreed upon a 2011 stipulation to implement the RIP to address reliability improvements that would ensure compliance with BPU standards and improve ACE's reliability performance.[21]

Q. Please summarize ACE's reliability commitments under the RIP.

A. Under the Phase II stipulation dated May 16, 2011, ACE committed to achieve and then maintain the following reliability metric improvements by 2016:

- A SAIDI of 160 minutes from a 2009 baseline of 211 minutes (a 25 percent reduction), and
- A SAIFI of 1.3 events from a 2009 baseline of 1.61 events (20 percent reduction).[22]

The goal of the reliability metrics was to be more stringent than required under N.J.A.C. 14:5-8.9 and show an improvement relative to the Company's 2009 reliability performance.[23]

---

[21] See I/M/O ACE, BPU Docket No. ER09080664, Order (May 16, 2011), Stipulation.
[22] Ibid. Page 7.

Q. What were the Company's SAIDI and SAIFI for 2016?

A. As shown in Figure 5 and Figure 6, the Company achieved a SAIFI of 1.18 events and a SAIDI of 125 minutes. It is self-evident that a SAIDI of 125 minutes is lower than the RIP target of 160 minutes, and a SAIFI of 1.18 events is lower than the RIP target of 1.3 events.

Q. What types of project categories did the Company propose to undertake as part of its RIP program?

A. Under the May 11, 2011 Phase II Stipulation, the Company proposed to undertake projects in the following categories:[24, 25]

- Enhanced Vegetation Management
- Priority Feeders
- Load Growth (Capacity Expansion)
- Distribution Automation (T&D Automation)
- Feeder Improvements (System Improvements)
- Substation Improvements

It is our understanding that the Enhanced Vegetation Management program is expensed whereas the other programs are capitalized.

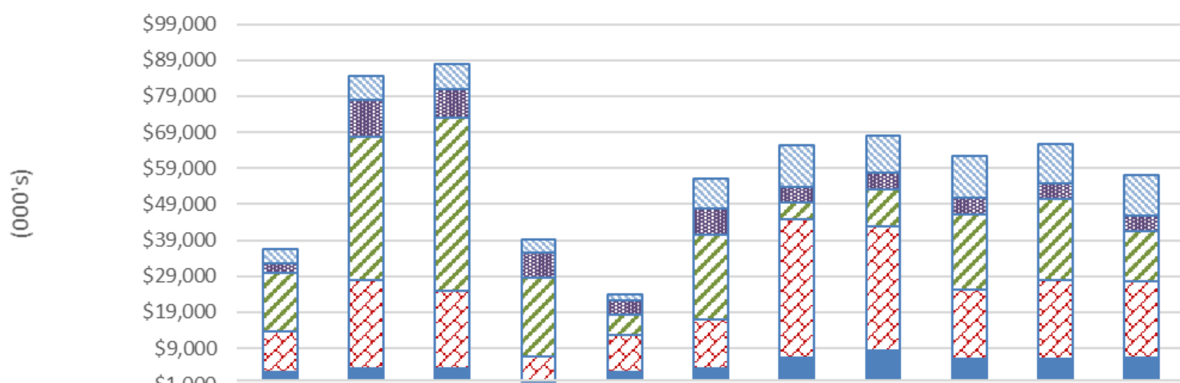
Q. Has the Company documented what it has spent and is projected to spend under the RIP program?

A. Yes, in response to RCR-ENG-12 and RCR-ENG-18, the Company provides its annual historical and projected capital spending for the RIP program. We have

[23] Ibid. Page 7.
[24] See I/M/O ACE, BPU Docket No. ER09080664, Order (May 16, 2011), Stipulation, page 5.
[25] In RCR-ENG-47, the Company noted that it had re-designated several categories. We have provided the new program names in parentheses.

combined the two responses below to show graphically the historical and projected capital spending for the RIP program.

Figure 7 Historical and Projected RIP spending[26]



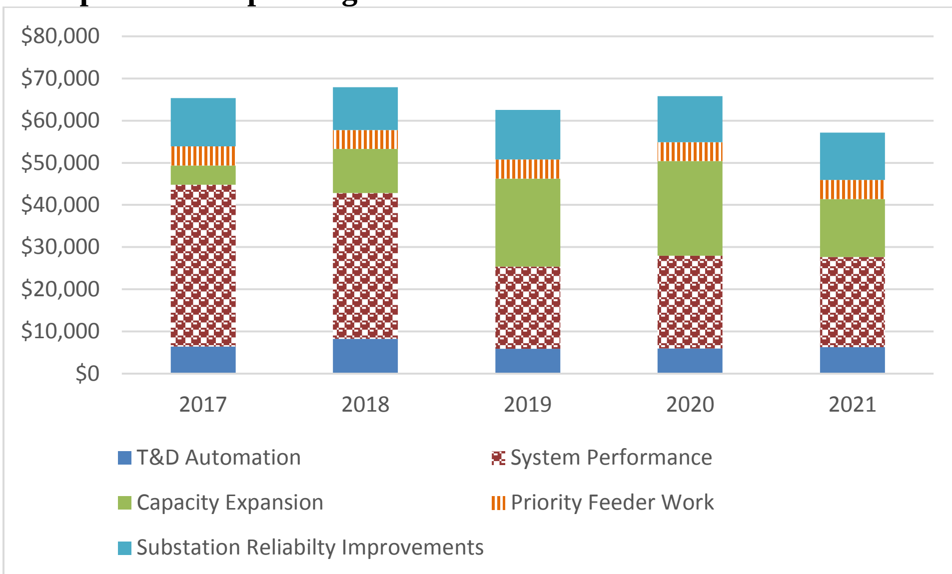
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Sub. Rel. Impr.	$3,774	$6,519	$6,836	$3,655	$1,515	$8,311	$11,451	$10,189	$11,778	$10,905	$11,272
Priority Feeder Work	$2,699	$10,337	$8,058	$6,970	$4,088	$7,228	$4,499	$4,499	$4,500	$4,500	$4,500
Capacity Expansion	$16,348	$39,937	$48,092	$21,915	$5,689	$23,820	$4,599	$10,405	$20,887	$22,425	$13,751
System Performance	$11,335	$24,354	$21,367	$6,573	$10,056	$13,348	$38,304	$34,590	$19,424	$21,936	$21,360
T&D Automation	$2,340	$3,495	$3,504	-$60	$2,535	$3,477	$6,491	$8,276	$5,950	$6,040	$6,299
Total	$36,497	$84,642	$87,858	$39,053	$23,882	$56,184	$65,345	$67,960	$62,539	$65,806	$57,183

Figure 7 shows that total capital spending for the RIP program peaked in 2013 at approximately $88 million and then decreased to about $24 million in 2015. The decrease in spending between 2014 and 2015 may reflect the Exelon-Pepco merger. The Exelon Merger Petition was filed in June 2014, and the Board approved a Stipulation resolving that matter in February 2015.[27] In this rate case, the Company proposes spending for the RIP program from 2017 through 2021 at an average of $63 million per year. A more detailed graph showing the

[26] RCR-ENG-12 Attachment 1, RCR-ENG-18 Attachment 1.
[27] See I/M/O Merger of Exelon Corporation and Pepco Holdings, Inc. BPU Docket No. EM14060581, Order Approving Stipulation of Settlement (February 11, 2015).

Company's proposed RIP capital spending for 2017-2021 from RCR-ENG-18 is shown below.

Figure 8 Proposed RIP Spending 2017-2021[28]



We note that the proposed RIP capital spending levels for 2017 through 2021 shown above in Figures 7 and 8 do not include the Company's PowerAhead spending of $79 million for the next five years that we discuss below.[29] These proposed budgets also do not include other capital spending, such as proposed spending on customer-driven improvements or general plant.

Q. What is your recommendation to the Board?

A. At this point in time, we recommend that the Company should not continue funding distribution reliability capital investments through the RIP program since it has met its 2011 RIP commitments. We also recommend that the Company should cease operational spending through its Enhanced Vegetation Management

[28] RCR-ENG-18. Attachment 1.
[29] See I/M/O ACE, BPU Docket No. ER16030252, Order Adopting Stipulation.(May 31, 2017), Stipulation.

program, which is a subset of the RIP. Instead, the Company should develop distribution capital and O&M expense budgets based on prioritization procedures that balance the cost versus benefits in its efforts to maintain and invest in its distribution system reliability at least costs to its customers. Its vegetation management spending should be based on what is required under the Board's new regulations.

VII. VEGETATION MANAGEMENT SPENDING

Q. Please summarize your conclusions regarding the Company's Enhanced Vegetation Management program.

A. The Company's vegetation management outage frequencies and durations have decreased since the implementation of its Enhanced Vegetation Management program that was a component of the 2011 RIP. That said, the Company is proposing significant increases in vegetation management spending to continue the Enhanced Vegetation Management program and to meet the BPU's new regulations governing vegetation management. We recommend that the Company evaluate and quantify the effects of the Board's vegetation management regulations to help inform future vegetation management spending.

Q. Has the Company made improvements in its tree related outages when compared to a 2009 baseline?

A. Yes. The following figure (Figure 9) shows improvement in the Company's tree related outage durations and frequencies for the period 2009-2016, excluding Major Events.

Figure 9 Vegetation Related Outage Duration and Frequency 2009-2016 (Major Events Excluded)[30]

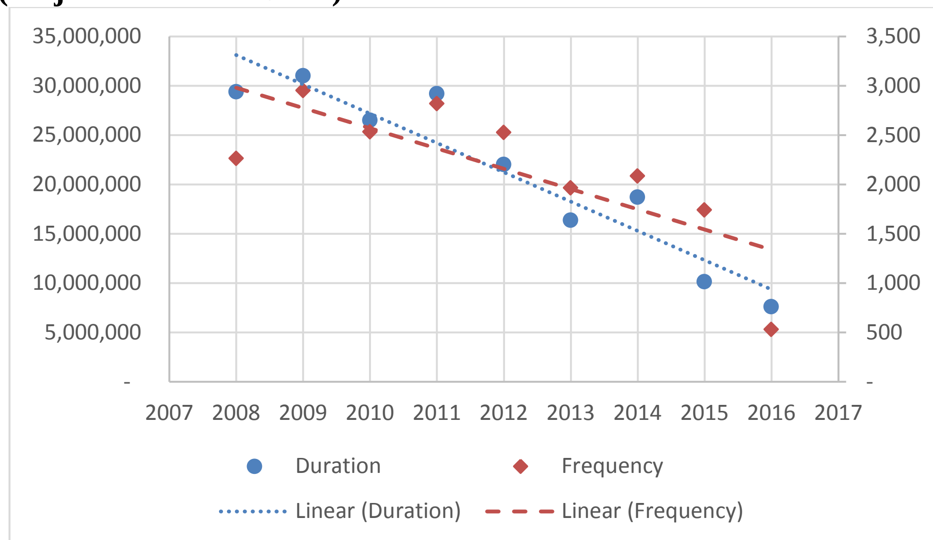


Figure 9 shows that since the baseline year of 2009, the Company's tree-related outage durations (excluding Major Events) have decreased at an average annual rate of 15.5 percent and its tree-related outage frequencies have decreased at an average annual rate of 16.5 percent. While the Company's tree-related outage frequencies and durations generally rank as the number 1 or 2 cause of outages, in 2016 tree-related outages fell in rank to the number 4 cause of outage durations and to rank number 6 for outage frequencies. However, we believe that at some point the Company's tree-related outage duration and frequencies will plateau since there is a limit to how much tree-trimming the Company can undertake.

[30] RCR-ENG-2 Attachments 3-8.

Q. What can be attributed to the Company's improvement in tree-related outages?

A. Under RIP, the Company undertook an Enhanced Vegetation Management program. This program as described by the Company is:

> Enhanced vegetation management includes tree trimming along public rights of way to obtain sufficient clearance between the overhead electric wires and existing trees. In addition to tree trimming, ACE also works with counties, communities and homeowners to remove diseased or dead trees which would damage the distribution system if they were to fall.
>
> For overhead systems, vegetation management (tree trimming) is ACE's largest single preventive maintenance program. ACE has had a routine cyclical program of tree trimming in place for 4 years. This program is designed to maintain minimum clearances between vegetation and overhead facilities.[31]

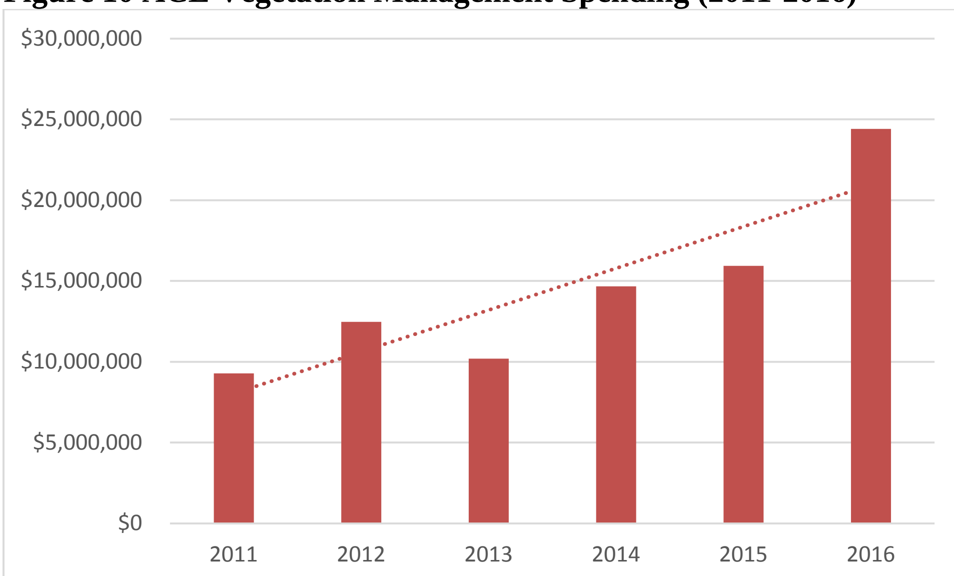
This program has manifested itself in the number of trimmed miles in its four-year tree trimming cycle. It appears that the Company's documentation of its tree trimming schedules started to appear in its 2012 Annual System Report.[32] In a separate filing, the Company noted that it had trimmed approximately 1,900 miles in 2012.[33] In the period between 2014-2016, the Company reported trimming approximately 1,780 or 1,900 miles per year or approximately 24 to 26 percent of the 7,276 circuit miles in the Company's service territory.[34]

[31] RCR-ENG-2 Attachment 3, Page 6.
[32] RCR-ENG-2 Attachment 3, Page 92.
[33] RCR-ENG-3 Attachment 3, Page 13.
[34] RCR-ENG-49.

Q. How much has the Company spent on vegetation management to achieve the observed improvements in tree-related outages and durations?

A. The Company's improvement in tree related outages and frequencies are reflected in the spending on vegetation management incurred by the Company as shown in the following figure (Figure 10).

Figure 10 ACE Vegetation Management Spending (2011-2016)[35]



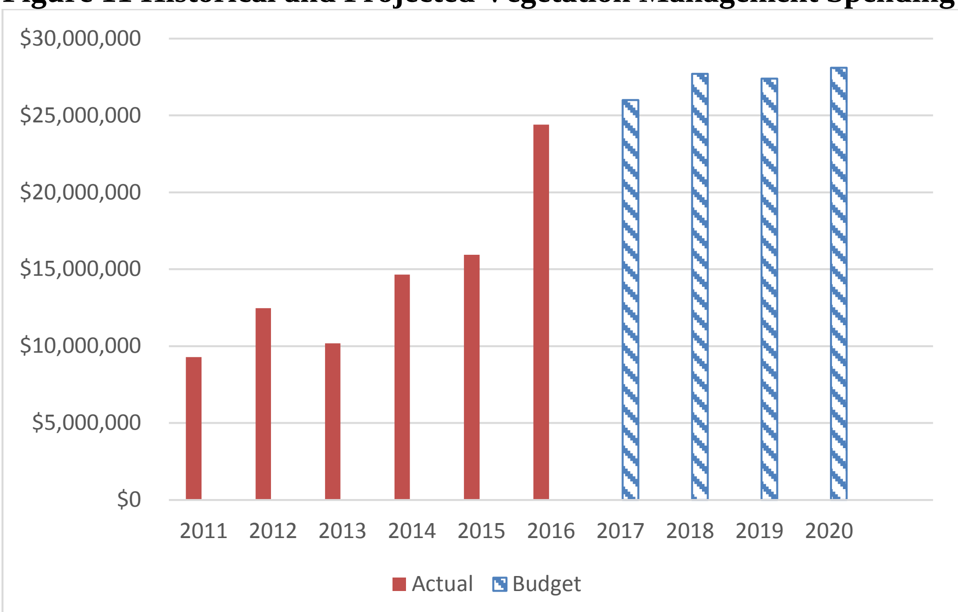
The Company's vegetation management spending, which includes the Company's Enhanced Vegetation Management Program, has increased since 2011 at an annual average growth rate of 21 percent.[36]

[35] RCR-ENG-23.
[36] Based on a comparison of vegetation management spending presented in RCR-ENG-23 and RIP vegetation management spending presented in RCR-ENG-3 Attachment 1, page 73.

Q. Does the Company project future spending increases for Vegetation Management?

A. Yes, the Company provides projections for future vegetation management spending in response to RCR-ENG-23. We have included those projections in the following figure (Figure 11) that builds upon Figure 10.

Figure 11 Historical and Projected Vegetation Management Spending[37]



The Company claims that the increased vegetation management budgets are the result of the BPU's new vegetation management regulations that came into effect in 2016.[38] We do not believe it is necessary for the Company to increase vegetation management expenses from $15.9 million in 2015 to $24.4 million in 2016 to comply with the new BPU vegetation management regulations. It appears to us that the regulation's requirement for trimming of each circuit from the

[37] RCR-ENG-23.
[38] Direct testimony of Michael Sullivan, adopted by William Ruggeri, page 16, line 18 to page 17 line 12.

substation to the first protective device as defined by the BPU are consistent with the Company's existing Enhanced Vegetation Management program.

Q. Please explain your understanding of the BPU's vegetation management regulations adopted in Docket EX15010033.

A. It is our understanding that the revised regulations generally follow initiatives already in place under the Company's Enhanced Vegetation Management program. The BPU regulations include:[39]

- Four-year trim cycle.
- Hazard tree identification and management program.
- The removal of overhanging vegetation from the substation to the first protective device starting in January 2016.
- Additional reporting requirements for vegetation management.

Apart from reporting requirements and explicitly defining the trim area of distribution lines, we believe that the Company has already implemented many of the policies outlined in the BPU's new regulation.

Q. Has the Company quantified the impacts of the new regulations on tree-related outages?

A. No, the Company has indicated that it has not quantified the impact of the new vegetation management standards on reliability.[40] The Company claims that it will need to complete an entire four-year trimming cycle to assess the effects of the new regulations. However, the new regulations incorporate almost all of the

[39] http://www.njslom.org/documents/NJ-RegulationsSubchapter9-electric.pdf
[40] RCR-ENG-7.

procedures that the Company has already implemented for vegetation management as part of its Enhanced Integrated Vegetation Management Program with the exception of additional trimming requirements between substations and the first protective device for each distribution circuit. This suggests that the new regulations should result in improvements in reliability performance over the Company's current RIP program.

Q. What is your recommendation to the Board regarding the Company's Vegetation Management program?

A. The Company has achieved success with its Enhanced Integrated Vegetation Management program when compared to the 2009 baseline levels and before the adoption of the new vegetation management regulations. At this point the Company has not quantified the amount of spending needed to support the new vegetation management regulation. We believe the new regulations should improve system reliability performance beyond that achieved with the Company's Enhanced Integrated Vegetation Management program and, on this basis, the RIP based program is no longer needed. We recommend that future vegetation management spending be developed outside of the auspices of the Enhanced Integrated Vegetation Management program as, like the rest of the RIP, the Company has already achieved the goals of this program. Instead, we recommend that the the Board require the company to quantify the level of spending needed to meet the regulations and that ACE's vegetation management budgets be set at those levels.

VIII. EXELON PEPCO MERGER COMMITMENTS

Q. Please summarize the Exelon merger reliability commitment.

A. As part of the Exelon merger settlement of 2015, Exelon made reliability commitments for ACE to continue to spend on RIP upon completion of the merger and for ACE to meet specified reliability targets by 2020.[41] The merger reliability commitments referenced in Mr. Ruggeri's adopted testimony are summarized below (Table 2):

Table 2 ACE Reliability Commitments and Performance

	Commitments			Performance		
Metric	N.J.A.C	RIP (2016)	Merger (2020)	2009	2015	2016
SAIFI	1.82	1.3	1.05	1.61	1.03	1.18
SAIDI		160		211	85	126
CAIDI	120		100	131	83	106

Notes
Major events excluded
Table 3 Michael Sullivan Direct Testimony
RCR-ENG-2 Attachment 8
May 16, 2011 Stipulation Docket ER09080664

While the 2020 reliability commitments are more stringent than the RIP commitments, the Company's 2015 reliability metrics for SAIFI was 1.03 and for CAIDI was 83. Although the Company's reliability performance in 2016 slipped from 2015, it is reasonable to conclude that the Company should be able to meet the 2020 merger-associated reliability targets.

[41] I/M/O Merger of Exelon Corporation and Pepco Holdings, Inc. BPU Docket No. EM14060581, Order Approving Stipulation Settlement (February 11, 2015), page 12. The calculations for the 2020 reliability commitments are based on a three-year historical average.

Q. Did the Company make any commitments on RIP spending as part of the merger?

A. Yes. Exelon made a commitment that it would continue the RIP and would maintain the following levels of spending on the RIP.[42]

Table 3 Merger RIP Commitments (millions)

Categories	2014	2015	2016	2017	2018	2019	2017-2019
Priority Feeders	$7.8	$5.0	$10.0	$10.0	$10.0	$5.0	$25.0
Load Growth	$20.1	$7.4	$23.2	$19.4	$23.5	$30.8	$73.7
Distribution Automation	$3.3	$3.3	$10.6	$8.6	$8.6	$6.1	$23.3
Feeder Improvement Plan	$6.7	$4.7	$7.5	$8.0	$8.5	$5.5	$22.0
Substation Improvement	$3.6	$1.5	$3.8	$4.6	$2.3	$0.7	$7.6
Total	$41.5	$21.9	$55.1	$50.6	$52.9	$48.1	$151.6
Vegetation Management	$14.4	$14.6	$14.6	$14.6	$14.6	$14.6	$43.8
Notes							
Exelon Merger Stipulation. Docket EM14060581, February 11, 2015							

This proposed RIP commitment budget from the Exelon merger proceeding for both capital and expenses would presumably incorporate the Company's estimate to meet the 2020 merger reliability commitments of 1.05 for SAIFI and 100 minutes for CAIDI shown on Table 2. However, the Company now seeks to do so at a higher overall cost. The following table shows the difference between the Exelon merger based RIP budgets shown in Table 3 above with the proposed 2017 RIP budgets shown in Figure 8 earlier in our testimony.

[42] Ibid. Page 12.

Table 4 RIP Budget Differences between actual and budgeted versus merger RIP Commitments

Categories	2016	2017	2018	2019	2017-2019
Priority Feeders	-$2.77	-$5.50	-$5.50	-$0.50	-$11.50
Load Growth	$0.62	-$14.80	-$13.10	-$9.91	-$37.81
Distribution Automation	-$7.12	-$2.11	-$0.32	-$0.15	-$2.58
Feeder Improvement Plan	$5.85	$30.30	$26.09	$13.92	$70.32
Substation Improvement	$4.51	$6.85	$7.89	$11.08	$25.82
Total	**$1.08**	**$14.74**	**$15.06**	**$14.44**	$44.24
Vegetation Management	$9.8	$11.4	$13.1	$12.8	
Notes					
RCR-ENG-12					
RCR-ENG-18					
RCR-ENG-23					

Table 4 shows that the Company's actual spending on the RIP capital projects in 2016 was $1.08 million higher than its merger commitments, and its actual spending was $9.8 million more for Vegetation Management expense than what the Company committed to in the Exelon merger proceeding. In future years (2017-2019), the amount of projected capital spending proposed by the Company in this proceeding is $44.24 million more than the amounts Exelon committed to in the Exelon merger proceeding. As we have stated previously, the Company has met its RIP reliability requirements so there does not appear to be a need for continued reliability spending specifically tied to the RIP.

Q. Beyond the 2020 reliability commitments and RIP spending, did Exelon make any additional commitments regarding reliability?

A. Yes. In addition to the firm 2020 reliability targets, Exelon made an additional commitment that it would "aspire" to achieve first quartile reliability performance for ACE.[43] While the Company did not commit to a specific timeline to meet this aspirational goal, the Company did commit to conduct an analysis of the incremental effort that it would take the Company to achieve first quartile reliability performance.[44]

Q. Did the Company conduct this analysis of the incremental effort required to reach first quartile performance?

A. Yes. In September 2016, the Company provided the report, *First Quartile SAIDI and SAIFI Performance Reliability Analysis for Atlantic City Electric Company Distribution System* ("2016 ACE Reliability Report"), which documented the Company's analysis of its 2020 reliability commitments and the incremental effort required to meet first quartile performance.

Q. What are some of the findings in the report?

A. The 2016 ACE Reliability Report indicated that it met the first quartile reliability metrics as required under the Exelon merger agreement stipulation.[45] That report provided an estimate of the budget at that point in time required by ACE to meet its 2020 reliability targets.[46] For the period 2017-2020, the Company's proposed capital and O&M expenses to meet the Merger SAIFI commitments would be \$189.2 million.[47] In the instant base rate case proceeding the Company is proposing a RIP capital and O&M expenses budget of \$268.2 million for the

[43] I/M/O Merger of Exelon Corporation and Pepco Holdings, Inc. BPU Docket No. EM14060581, Order Approving Stipulation Settlement (February 11, 2015), page 12.
[44] Ibid. Page 12.
[45] *First Quartile SAIDI and SAIFI Performance Reliability Analysis for the Atlantic City Electric Company Distribution System* (September 23, 2016).
[46] Ibid. Table 1.
[47] Ibid. Table 1.

program that would improve SAIFI: Priority Feeder, Distribution Automation (T&D Automation), Feeder Improvement (System Performance), and Enhanced Vegetation Management. In the instant base rate case, the Company is proposing an increase of $79 million in capital and O&M expenses over the amounts identified in its 2016 report.

Q. Does the Company estimate that incremental effort to reach first quartile SAIFI?

A. Yes. On page 11, Table 3 of the 2016 ACE Reliability Report, the Company showed that a total of $117 million between 2017 and 2020 would be sufficient to reach first quartile SAIFI performance.[48] The $117 million budget would be used by the Company for SAIFI related projects. These SAIFI projects are a combination of the existing Priority Feeder, Distribution Automation (T&D Automation), and Feeder Improvement (System Performance) programs already in the existing RIP. In the instant base rate case, the Company has budgeted $159 million in RIP spending for these three programs between 2017 and 2020 which is $42 million more than contemplated in its 2016 report. Moreover, in the instant base rate case, ACE does not explicitly guarantee that it would achieve first quartile performance.

Q. What do you conclude from the 2016 ACE Reliability Report?

A. While it is difficult to map the capital and O&M categories between the 2016 ACE Reliability Report and the proposed RIP spending in the instant base rate

[48] Ibid. Table 3.

case, it does appear that the spending amounts proposed in the instant base rate case exceed the amounts previously identified by the Company as recently as 2016 in order to achieve both the Exelon Merger reliability commitments and the first quartile SAIFI aspirations.

IX. SYSTEM REPLACEMENT RECOVERY MECHANISM

Q. Please summarize your concerns regarding the Company's proposed System Replacement ("SRR") Mechanism.

A. We understand that other Rate Counsel witnesses address other aspects of the proposed SRR mechanism. Our concern is that the proposed mechanism would generally include projects that are routine in nature and normally included in typical distribution budgets. Routine projects needed by the Company to provide safe and reliable service should not require a separate tracker mechanism. Rather, such projects should undergo the same rigor of review as other Company expenditures to insure that the most cost effective projects are being selected.

Q. Do you believe that the specific projects included in the SRR mechanism are appropriate?

A. No. It is clear that there is a significant amount of uncertainty concerning future distribution system expenditures. Factors such as load growth, asset conditions, vegetation management requirements, storm hardening, and reliability performance all play an important role in establishing budgetary requirements. However, future projections for each of these factors cannot be established with any degree of certainty. As is evident in the Company's descriptions of projects included in its budget projections there are a number of projects that may come or go based on updated system conditions, regulatory requirements or system performance. Establishment of funding for many of these future projects is little more than speculation at this point in time.

Q. Does the proposed SRR mechanism include the Company's PowerAhead Program?

A. No. The Board should be aware that the issues in this base rate case do not include spending that was agreed upon for the Company's PowerAhead program to improve resiliency under major events across its distribution system. Based on the terms of the PowerAhead settlement in BPU Docket No. ER16030252, ACE will spend an additional $79 million over five years in the following categories:

Table 5 ACE PowerAhead Program

Category	Amount (millions)
Structural and Electrical Hardening	$24
Selective Undergrounding	$11
Barrier Island Feeder Ties	$13
Distribution Automation	$15
Electronic Fusing	$2
New Substation – Harbor Beach	$14
Total	**$79**
Notes Stipulation. Docket ER16030252. May 3, 2017. Page 4	

While the PowerAhead reliability projects will benefit the Company under major events, these same projects should also help improve "blue-sky" reliability. The proposed SRR mechanism would be in addition to the projects initiated under the PowerAhead program.

X. POST-TEST YEAR ADJUSTMENTS

Q. Please summarize your concerns regarding the Company's Post Test Year Adjustments.

A. We understand that Rate Counsel witness Ms. Andrea Crane has sponsored testimony that also addresses concerns regarding the Company's post-test year adjustments. We find that the Company has not specifically identified the importance of any one of the projects in its list, and therefore we believe that it would be inappropriate to include any of the Company's post-test year adjustments as being major in consequence.

Q. What is your understanding of the standard for post-test year adjustments?

A. It is our understanding that the Board has accepted post-test year adjustments provided there is clear a likelihood that such proposed rate base additions shall be in service by the end of the period, that such rate base additions are major in nature and consequence, and that such additions be substantiated with very reliable data. We understand that these criteria were approved by the Board in the 1985 Elizabethtown Water Company case.[49]

Q. Does the Company provide a list of post-test year adjustments?

A. Yes, we note that Schedule (JCZ)-12 identifies $52.6 million of post-test year projects. Of those post-test year projects, the many of items are designated as "blankets" or recurring spending that would be considered routine spending. Mr. Sullivan notes in his testimony: "The individual projects are inextricable parts of

[49] See In RE Elizabethtown Water Company Rate Case, BPU Docket No. WR8504330, Decision (5/23/85).

an overall investment strategy, but are not assigned importance by cost consideration or inherent function."[50] We calculate that the Company has only identified eight individual projects that cost over $100,000. Together these eight specific projects represent only $3,263,000 of the $52,691,000 post-test year adjustments. Moreover, the Company has not designated any one of the eight projects as major in nature and consequence.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q. What are your recommendations?

A. Our findings and recommendations are summarized as follows:

- ACE has met the goals of the 2011 Reliability Improvement Plan ("RIP") thus alleviating the need for the Company to continue budgeting projects under the RIP. RIP capital spending has historically represented 21 to 49 percent of the Company's overall distribution capital spending.
- We recommend that Company should discontinue both capital and operational spending under the RIP program.
- Instead of the RIP programmatic spending, the Company should identify projects and programs to improve reliability based on a prioritization process that considers costs versus benefits and that establishes a cost-effective budget.
- We similarly recommend that the Company should cease operational spending through its Enhanced Integrated Vegetation Management program, which is a

[50] Direct Testimony of Michael Sullivan adopted by William Ruggeri, page 27, lines 4-7.

subset of the RIP. Instead, we recommend that the Board require the Company to quantify the appropriate level of vegetation management spending that will be needed to meet the new vegetation management regulations and base its spending on those requirements.

- The Board should reject the Company's proposed System Renewal Recovery ('SRR") mechanism since the proposed program includes mostly blanket spending that should be part of the Company's normal course of business as well as funding for future projects that are highly uncertain with respect to scope and timing.
- The Board should reject the Company's post-test year adjustments since most of the adjustments are generally for programs and blankets. The Company has not demonstrated that any of the post-test year adjustments are major in consequence as set forth in the Elizabethtown standard. Individual projects of more than $100,000 in capital spending only represent $3.2 million of the $52 million post-test year adjustments proposed by the Company.

Q. Does this conclude your testimony?

A. Yes. However, we reserve our right to modify our testimony based on additional information provided by the Company.

ATTACHMENT RC-ENG-1

Charles P. Salamone P.E.

Profession: Power systems analysis and assessment, with a special emphasis on transmission planning, performance and design

Nationality: U.S. Citizen

Years of Experience: 40 years

Education B.S.E.E, Power System Engineering, 1973
Gannon University, Erie, PA

Position: Owner/Manager, Cape Power Systems Consulting

Web/Email: www.CapePowerSystems.com csalamone@capepowersystems.com

Contact Number: 774-271-0383

Summary: Mr. Salamone provides professional services based on 40 years of electric utility industry experience in the areas of Transmission Planning, Substation Planning, Distribution Planning, ISO-New England Planning Procedures, New England Power Pool Procedures, Congestion Management, Generator Interconnections, Planning/Capital Budget Management, Meter Engineering, and State (Mass DPU and New Jersey Rate Council) and Federal (FERC) Regulatory Agency Filing Development and Expert Witness Testimony

Experience:

2005- Pres. **Cape Power Systems Consulting**

Established a power system design, analysis, planning and assessment consulting company to work directly with diverse power system stakeholders.

- Worked with a number of clients for the development of analysis, reports and presentations in support of regulatory and technical review/approval process for transmission and distribution projects
- Provided technical assistance for transmission planning activities for an Independent System Operator including support for major transmission system expansion programs and development of a 10 year transmission plan
- Worked with a large Massachusetts Utility as an expert witness in support of State regulatory reviews for the siting of a major transmission system upgrade plan

- Worked with state regulatory agencies in support of electric utility rate case proceedings including expert witness testimony and assessment of electric utility performance
- Worked with multiple state regulatory agencies in support of review of electric utility smart grid initiatives including review of the technical performance, system benefits and viability of proposed electric utility programs
- Developed and conducted a comprehensive training program for implementation of an Energy Management System (EMS) based transmission system security assessment application for a large Massachusetts utility
- Worked with clients to conduct load flow assessment of transmission system performance for feasibility and reliability performance studies across New England and New York

1979-2005 NSTAR (Previously Boston Edison and Commonwealth Electric)

2000-2005 ***Director System Planning***

NSTAR (Previously Boston Edison and Commonwealth Electric) Boston, MA

- Responsible for long term planning of Company transmission, substation and distribution systems
- Successfully managed the studies, design, internal and external review and regulatory approval for a $250M 345 kV underground transmission expansion project serving the greater Boston area
- Managed numerous generator interconnection studies, design and approvals
- Successfully managed studies, design and approval for congestion mitigation plans and expansion project
- Oversaw transmission and distribution planning efforts to establish a comprehensive 10 year $300 million system expansion plan
- Served as Company representative on NEPOOL Reliability Committee and the New England Transmission Expansion Advisory Committee
- Served as Company expert witness for system planning related regulatory proceedings at both the state and federal levels.
- Supervised a staff of 10 senior engineers

1989-1999 ***Manager, System Planning and Meter Services***

Commonwealth Electric Company, Wareham, MA

- Develop risk based prioritized $10 million construction budget procedures
- Supervise a staff of 6 professional engineers and 4 analysts
- Served as chair of the NEPOOL Regional Transmission Planning Committee (currently the NEPOOL Reliability Committee)
- Process billing determinant and interval data for all major system customers
- Lead implementation of first MV90 meter data processing system
- Develop annual performance analysis reports for all transmission and major distribution systems

- Manage multiple FERC tariff based transmission customer and generation developer system impact studies
- Served as expert Company witness in State and FERC regulatory proceedings
- Implemented a risk index for prioritization of all transmission and major distribution construction projects
- Implemented automated electronic processing of major customer billing data, which significantly reduced time needed to generate bills
- Served as lead member on information technology company merger team
- Implemented process and equipment to perform all tie line, generator and wholesale customer meter testing
- Served as chair of the NEPOOL Planning Process Subcommittee, which established numerous NEPOOL policies for transmission/generator owners
- Served as Vice-Chair of the NEPOOL Reliability Committee

1984-1989 ***Meter Engineer***

Commonwealth Electric Company, Plymouth, MA

- Designed and supervised installation of 15 generator meter data recorders
- Developed customer load plotting and analysis software
- Developed meter equipment order data processing system for four remote offices
- Implemented PC control of meter test boards, which significantly reduced processing and record keeping time
- Managed programming of all electronic meter registers to insure accurate data registration

1979-1984 ***Computer Application Engineer***

Commonwealth Electric Company, Wareham, MA

- Implemented numerous technical and analytical software applications for engineering analysis
- Served as member of decision team for implementation of a new SCADA system

1978-1979 **San Diego Gas & Electric, *Planning Engineer***

San Diego Gas & Electric Company, San Diego, CA

- Performed extensive stability analysis for a new 230 kV transmission interconnection with Mexico
- Performed transmission design and performance analysis for a new 250 mile 500 kV line from San Diego to Arizona

1973-1978 **New England Gas & Electric Association, *Planning Engineer***

New England Gas & Electric Association, Cambridge, MA

- Performed extensive stability analysis for a new 560 MW generating plant on Cape Cod
- Developed transmission plan for a new 345 kV transmission line on Cape Cod
- Developed plans for design and sighting of new 115 / 23 kV substations on Cape Cod

ATTACHMENT RC-ENG-2

Maximilian Chang, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 2 I Cambridge, MA 02139 I 617-453-7027
mchang@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, 2013 – present, *Associate*, 2008 – 2013.

Consults and provides analysis of technologies and policies, electric policy modeling, evaluation of air emissions of electricity generation, and other topics including energy efficiency, consumer advocacy, environmental compliance, and technology strategy within the energy industry. Conducts analysis in utility rate-cases focusing on reliability metrics and infrastructure issues and analyzes the benefits and costs of electric and natural gas energy efficiency measures and programs.

Environmental Health and Engineering, Newton, MA. *Senior Scientist*, 2001 – 2008.

Managed complex EPA-mandated abatement projects involving polychlorinated biphenyls (PCBs) in building-related materials. Provided green building assessment services for new and existing construction projects. Communicated and interpreted environmental data for clients and building occupants. Initiated and implemented web-based health and safety awareness training system used by laboratories and property management companies.

The Penobscot Group, Inc., Boston, MA. *Analyst*, 1994 – 2000.

Authored investment reports on Real Estate Investment Trusts (REITs) for buy-side research boutique. Advised institutional clients on REIT investment strategies and real estate asset exchanges for public equity transactions. Wrote and edited monthly publications of statistical and graphical comparison of coverage universe.

Harvard University Extension School, Cambridge, MA. *Teaching Assistant*, 1995 – 2002.

Teaching Assistant for Environmental Management I and Ocean Environments.

Brigham and Women's Hospital, Boston, MA. *Cancer Laboratory Technician*, 1992 – 1994.

Studied the biological mechanism of tumor eradication in mouse and human models. Organized and performed immunotherapy experiments for experimental cancer therapy. Analyzed and authored results in peer-reviewed scientific journals.

EDUCATION

Harvard University, Cambridge, MA
Master of Science in Environmental Science and Engineering, 2000

Cornell University, Ithaca, NY
Bachelor of Arts in Biology and Classics, 1992

REPORTS

Kallay, J., A. Napoleon, M. Chang. 2016. *Opportunities to Ramp Up Low-Income Energy Efficiency to Meet States and National Climate Policy Goals*. Synapse Energy Economics.

Vitolo, T., M. Chang, T. Comings, A. Allison. 2015. *Economic Benefits of the Proposed Coolidge Solar I Solar Project*. Synapse Energy Economics for Coolidge Solar I, LLC.

Chang, M. 2014. *Making the Grid More Resilient within Reason: Case Study in Public Service Electric and Gas "Energy Strong" Petition.*

White, D. E., M. Chang, B. Biewald. 2013. *State Energy Efficiency Embedded in Annual Energy Outlook Forecasts: 2013 Update*. Synapse Energy Economics for U.S. Environmental Protection Agency.

Hornby, R., P. Chernick, D. White, J. Rosenkranz, R. Denhardt, E. A. Stanton, J. Glifford, B. Grace, M. Chang, P. Luckow, T. Vitolo, P. Knight, B. Griffiths, B. Biewald. 2013. *Avoided Energy Supply Costs in New England: 2013 Report.* Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

Nogee, A., M. Chang, P. Knight, E.A. Stanton. 2013. *Electricity Market Restructuring and the Nuclear Industry.* Synapse Energy Economics for Whitt Law.

Koplow, D., M. Chang. 2013. *Vogtle 3 and 4 Conditional Loan Guarantee: Review of Documents Pertaining to Department of Energy Conditional Loan Guarantees for Vogtle 3 & 4.* Synapse Energy Economics and Earth Track.

Chang, M., D. White, E. Hausman. 2012. *Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation.* Synapse Energy Economics for Consumers Against Rate Hikes.

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Synapse Energy Economics for Energy Future Coalition.

Chang, M., D. White, P. Knight, B. Biewald. 2012. *Energy Benefits Resulting from the Investment of 2010 RGGI Auction Revenues in Energy Efficiency*. Synapse Energy Economics for Regulatory Assistance Project.

Chang, M., D. White, E. Hausman, N. Hughes, B. Biewald. 2011. *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the US.* Synapse Energy Economics for Union of Concerned Scientists.

Hornby, R., P. Chernick, C. Swanson, D. White, J. Gifford, M. Chang, N. Hughes, M. Wittenstein, R. Wilson, B. Biewald. 2011. *Avoided Energy Supply Costs in New England: 2011 Report.* Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

Chang, M., D. White, L. Johnston, B. Biewald. 2010. *Electricity Energy Efficiency Benefits of RGGI Proceeds: An Initial Analysis*. Synapse Energy Economics for Regulatory Assistance Project.

Fisher, J., J. Levy, P. Kirshen, R. Wilson, M. Chang, J. Kallay, C. James. 2010. *Co-Benefits of Energy Efficiency and Renewable Energy in Utah*. Synapse Energy Economics for the State of Utah Energy Office.

Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. Synapse Energy Economics for US Environmental Protection Agency.

Hornby, R., P. Chernick, C. Swanson, D. White, I. Goodman, B. Grace, B. Biewald, C. James, B. Warfield, J. Gifford, M. Chang. 2009. *Avoided Energy Supply Costs in New England: 2009 Report*. Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

Biewald, B., D. White, J. Fisher, M. Chang, L. Johnston. 2009. Incorporating Carbon Dioxide Emissions Reductions in Benefit Calculations for Energy Efficiency: Comments on the Department of Energy's Methodology for Analysis of the Proposed Lighting Standard. Synapse Energy Economics for New York State Attorney General.

ABSTRACTS

Koehler, D., M. Chang. 1999. “Search and Disclosure: Corporate Environmental Reports.” *Environment* 41 (2): 3.

Makoto, N., P. S. Goedegebuure, U. L. Burger, M. Chang, T. J. Eberlein. 1995. “Successful adoptive immunotherapy (AIT) is dependent on the infiltration of host CD8+ and CD4+ T cells into tumor.” *Surgical Forum* 66:528–531.

Burger, U.L., M. Chang, P. S. Goedegebuure, T. J. Eberlein. 1994. “Changes in host T-cell concentrations but not in donor TIL concentrations at the tumor site following adoptive immunotherapy.” *Surgical Forum* 45 (0): 513–515.

Burger, U.L., M. Chang, S. L. Adams, D. D. Schoof, T. J. Eberlein. 1993. “The role of CD4+ and CD8+ T-cells during TIL+ rIL-2 treatment in cancer immunotherapy.” *Surgical Forum* 64:467–469.

Zuber, M., D. L. Leonard-Vidal, A. L. Rubinstein,A. F. Massaro, M. Chang, D. D. Schoof, T. J. Eberlein. 1990. “In vivo efficacy of murine tumor-infiltrating lymphocytes (TIL) reactivated by anti-CD3.” *Journal of Cancer Research and Clinical Oncology* 116; A3.112.28.

Eberlein, T.J., A. F. Massaro, S. Jung, A. L. Rubinstein, U. L. Burger, M. Chang, D. D. Schoof. 1989. “Cyclophosphamide (Cy) immunosuppression potentiates tumor-infiltrating lymphocytes (TIL) therapy in the mouse.” Proceedings Annual Meeting: American Association Cancer Research. A30.A1472.

TESTIMONY

Maryland Public Service Commission (Docket No. 9431): Direct testimony on the applications of US Wind and Skipjack Wind for the development of offshore wind projects pursuant to the Maryland Offshore Wind Energy Act of 2013. On behalf of Maryland Office of People's Counsel. February 15, 2017.

Kansas Corporation Commission (Docket No. 16-KCPE-593-ACQ): Direct testimony on clean energy and coal fleet retirement concerns related to the petition of Great Plains Energy Inc., Kansas City Power and Light, and Westar Energy, Inc. for the acquisition of Westar by Great Plains Energy. On behalf of Sierra Club. December 16, 2016.

Maryland Public Service Commission (Docket No. 9424): Direct testimony on Delmarva Power and Light Company's application for a rate adjustment to recover smart grid costs. On behalf of Maryland Office of People's Counsel. October 7, 2016.

Maryland Public Service Commission (Docket No. 9418): Direct testimony on Potomac Electric Power Company's application for a rate adjustment to recover smart grid costs. On behalf of Maryland Office of People's Counsel. July 6, 2016.

Illinois Commerce Commission (Docket No. 16-0259): Direct and rebuttal testimony on Commonwealth Edison Company's annual formula rate update and revenue requirement reconciliation on distribution and business intelligence investments. On behalf of the Office of Illinois Attorney General. June 29, 2016 and August 11, 2016.

Maryland Public Service Commission (Docket No. 9406): Direct testimony on Baltimore Gas and Electric Company's application for a rate adjustment to recover smart grid costs. On behalf of Maryland Office of People's Counsel. February 8, 2016.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in storm hardening measures. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Hawaii Public Utilities Commission (Docket No. 2015-0022): Direct testimony on reliability, clean energy, competition, and management and performance concerns related to the petition of NextEra Corporation and Hawaiian Electric Companies (HECO) for the acquisition of HECO by NextEra. On behalf of the Hawaii Division of Consumer Advocacy. August 10, 2015.

Delaware Public Service Commission (Docket No. 14-193): Direct testimony evaluating the benefits and commitments of the proposed Exelon-Pepco merger. On behalf of the Delaware Department of Natural Resources. December 12, 2014.

State of New Jersey Board of Public Utilities (Docket No. EM14060581): Direct testimony on the reliability commitments filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities. On behalf of the New Jersey Division of Rate Counsel. November 14, 2014.

District of Columbia Public Service Commission (Formal Case No. 1119): Direct and answer testimony on the reliability, risk, and environmental impacts of the proposed Exelon-Pepco merger. On behalf of the District of Columbia Government. November 3, 2014 and March 20, 2015.

United States District Court District of Maine (C.A. No. 1:11-cv-00038-GZS): Declaration regarding the ability of the New England electric grid to absorb the impact of a spring seasonal turbine shutdown at four hydroelectric facilities. On behalf of Friends of Merrymeeting Bay and Environment Maine. March 4, 2013.

State of Maine Public Utilities Commission (Docket 2012-00449): Testimony regarding the Request for Approval of Review of Second Triennial Plan Pertaining to Efficiency Maine Trust. On behalf of the Maine Efficiency Trust. January 8, 2013.

New Jersey Board of Public Utilities (Docket No. GO12050363): Testimony regarding the petition of South Jersey Gas Company for approval of the extension of energy efficiency programs and the associated cost recovery mechanism pursuant to N.J.S.A 48:3-98:1. On behalf of the New Jersey Division of Rate Counsel. November 9, 2012.

Resume dated February 2017